LOON ENERGY INC.

2004 Annual Report

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Stockholder Information

As of December 31, 2004, the number of common shares outstanding was 45,729,708. As of the date if this annual report, the number of common shares outstanding is 67,136,344. The Annual & Special General Meeting of Loon Energy Inc. will beheld at 3:00 pm Calgary time on Wednesday, June 8, 2005 at the Calgary Petroleum Club, 319 – 5th Avenue SW, Calgary, Alberta, Canada.

Loon Energy Inc. is a Canadian public company with international oil and gas exploration and development operations in Latin America and south-central Europe. The common shares of Loon trade on the TSX Venture Exchange (TSX-V) under the symbol "LEY".

Message To Shareholders

Loon took significant steps during the 2004 fiscal year and in the first part of 2005 toward its goal of becoming an international exploration and production company.

A CHANGE IN DIRECTION

A major change in direction took place in February 2005 when Loon entered in to an agreement with Kappa Energy Colombia Limited S.A. to acquire a 49% interest in the Abanico Association Contract which covers more than 312 square miles (> 200,000 acres) of prospective oil and gas lands in the prolific Magdelena Basin area of central Colombia. Under the terms of the agreement Loon has agreed to fund US$6 million worth of exploration work and in particular has agreed to fund the drilling of three wells starting in June of 2005. One of these wells will target the seismically defined Aleli Prospect which is located 9 miles from Nexen's 120 million barrel Guando oil field. The Company estimates that the Aleli prospect could contain reserves in excess of 100 million barrels.

WORK IN SLOVENIA

In 2004 we participated in the drilling of two wells in Slovenia. The first well, at Pt-123, was drilled to a depth of 2,100 metres and was tested and completed in the Lovaszi reservoir. The well is currently producing gas at an average rate of approximately 250 Mcfd with all production being sold to a power plant located near the field. A second pressure build-up test will be conducted during the month of May after which the Company will be able to make a more accurate estimate of recoverable reserves. In the event the reserves are in line with our earlier estimate of 2 to 4 Bcf, Loon will plan a program for the rest of 2005 to increase overall natural gas production from the Lovaszi reservoir. This program may include stimulation of the existing producing zone, accessing the reservoir at another location through working over an existing well or the drilling of a new well or wells.

The second well, at D-14, was spud in October of 2004 and drilled to a depth of 2,805 metres. The main target of the well was the Pg reservoir, a tight gas reservoir that underlies the Petisovic-Dolina oil field. Pursuant to a farmout agreement with Grove Energy Limited, Grove retained Troy Ikoda Limited, a U.K. based third party engineering company to review the Pg reservoir to assess the potential gas-in-place ("GIIP"). This work resulted in Troy Ikoda estimating P90 GIIP of 228 Bcf. Subsequent to receipt of the report, Grove committed to pay for the drilling and fracture stimulation of the D-14 well.

In January of 2005 a stimulation program consisting of three fracs in separate sand units within the Pg reservoir was undertaken. There were significant well control issues following two of the fracture stimulations and large volumes of kill fluid and well control material were pumped into the well. We believe that the foreign materials introduced into the formation may have played a role in the inability of the well to produce commercial quantities of gas. The parties to the Slovenian joint venture are currently assessing what remedial work may be required on the D-14 well in order to obtain commercial gas production.

RESERVES

The only commercial oil and gas production during the 2004 fiscal year came from minor interests in Canada which produced an average of 32 boepd. The net present value of these assets at a 10% discount factor ($612,000 based on forecast prices) is not material to a valuation of the Company.

FINANCING COMPLETED

Loon raised $20 million in March of 2005 to fund work programs in both Colombia and Slovenia and to facilitate the evaluation of additional investment opportunities. Loon is now well capitalized and it will use its strong financial position to build upon existing projects and actively pursue the expansion of operations into other areas with potential to create wealth for our shareholders.

On behalf of the Board of Directors,

"signed"

Norman W. Holton
Chairman

May 4, 2005

The audited financial statements for the year ended December 31, 2004, the Management Discussion & Analysis (MD&A) and the Statement of Reserves Data and Other Oil and Gas Information (Form 51-101 F1) were filed in accordance with National Instrument 51-101 and may be accessed at www.sedar.com.

Highlights 2004

February

Debenture Term Extended – Warrants Granted

The TSX Venture Exchange approved the extension of the term for $800,000 in convertible debentures and the grant of warrants in consideration for the extension. The debentures were originally issued in July, 2001 for a term of two years. The expiry date was extended until January, 2006. In consideration for the extension, Loon issued 1,600,000 warrants, with the same expiry date, to purchase Loon common shares at $0.10 per share.

March

Deal with Grove on Deep Gas Potential in Slovenia

Loon and its partners finalized an agreement with Grove Energy Limited under which Grove could acquire 65% of the rights of Loon and its joint venture partners in the deeper gas zones which underlie the Petisovci-Dolina field area in Slovenia. Grove agreed to expend a minimum of 4.2 million Euros evaluating the potential zones below a depth of approximately 2,000 metres.

Interest in European Ventures Increased

Auldstone Investments Inc., a joint venture partner of Loon in Slovenia, entered into an agreement with Loon under which the Company acquired all of Auldstone's interests in the Slovenian joint venture.

Debenture Converted

The $800,000 in convertible debenture debt was converted into 8,000,000 common shares of Loon.

April

Auldstone Acquisition Closed

Loon issued 4,400,000 common shares as consideration on the closing of the acquisition of Auldstone's interests in the Slovenian joint venture.

New Director Appointed

John I. Bitove of Toronto, Ontario, Canada joined the board of directors. Mr. Bitove is one of Canada's leading entrepreneurs with a distinguished record of accomplishments in business and community service. He is the majority owner of Scott's Restaurants Inc. and Chairman.

Pt-123 Well Licensed

Loon received a permit to drill the Pt-123 well in Slovenia to evaluate multiple oil and gas targets.

May

Grove Agreement Amended

Loon and its joint venture partners in Slovenia reached agreement with Grove to amend the terms of the agreement with respect to the deep gas potential underlying the Petisovci-Dolina area of eastern Slovenia to include a firm well commitment by Grove.

Private Placement

The Company issued 9,990,000 common shares at a price of $0.18 per common share for gross proceeds of $1,798,200 in an un-brokered private placement.

July

Engineering Report on Pg Gas Reservoir

Troy Ikoda Limited, an independent UK-based engineering firm, completed an initial report on the Petisovci-Globocki ("Pg") gas reservoirs underlying Loon lands in eastern Slovenia. The Pg gas reservoirs are the primary target of the option agreement with Grove. The report estimated P90 gas-in-place of 228 Bcf and P50 gas-in-place of 420 Bcf. Actual recovery of natural gas from the Pg will be dependent upon the success of any stimulation undertaken.

Pt-123 Spuds

The drilling of the Pt-123 well commenced on July 27th.

August

Pt-123 Cased to Total Depth

The well was cased to its total depth of 2,080 metres early in the month and a service rig was moved on to the location August 30th.

D-14 Well

The D-14 appraisal well spud on August 28th. The well was 100% funded by Grove Energy Limited as a part of its earning obligations for the deeper gas zones. Loon has a 10.5% carried working interest in the well. The well targeted multiple tight gas sands in the Pg zone.

October

Gas in Pt-123 Well

A 5 metre gas zone encountered at a depth of 1,530 metres was tested at a stabilized rate of 600 Mcfd (100 boepd) after a two day production test. Loon paid 40% of the well costs and will receive 38% of the net revenue prior to payout of costs and 30% thereafter.

Gas in D-14 Well

Gas was encountered in the upper part of the well but equipment constraints and the condition of the wellbore precluded testing in the open hole. The gas zone was preserved behind intermediate casing which was run to a depth of 1,803 metres. The interest of Loon in this gas zone is the same as its interests in the Pt-123 well as the agreement with Grove applies only to zones in the Pg below a depth of approximately 2,000 metres.

November

Pt-123 Production Testing

An extended production test of the gas zone, discovered in the drilling of the well during July and August, started in early November. Produced gas is delivered through existing field lines to a power plant located within 3 kilometres of the well. The initial test rate was 350 Mcfd.

December

Stimulation of D-14 Underway

A fracture stimulation program began in early December. The program, which comprised the perforation and fracturing of three separate intervals, continued into the first quarter of 2005.

Highlights 2005

February

Fracture Stimulation of D-14 Well

Production testing of tight gas sands in the Pg zone began. The sands had been fracture stimulated during the month of January and the early part of February.

Loon Negotiates Deal in Colombia

Loon announced that it had entered into an agreement to explore for and produce hydrocarbons in Colombia. Loon will expend a minimum of US$6 million to participate in a 3-D seismic program and drill a minimum of three wells to earn a 49% interest in more than 312 square miles of lands.

March

Update on D-14 Well

The well continues to flow minor amounts of gas. Well is showing signs of formation damage and it is believed that the damage may have occurred during the fracture stimulation process.

Financing Closed

A "bought deal" private placement was closed raising total gross proceeds of approximately $20 million. The offering consisted of 21,052,636 common shares at $0.95. The net proceeds of the offering will be used for the drilling of exploration and development wells and the shooting of 3-D seismic in Colombia, working capital and/or expanded capital expenditures.

April

Colombia – Drilling & Seismic Plans

Loon announced that the 3-D seismic will be shot during the second quarter of the 2005 fiscal year and that the first of the earning wells is expected to spud in late June.

Operations

COLOMBIA

Deal Summary

On February 18, 2005, Loon announced that it had entered into an agreement with Kappa Energy Colombia Limited S.A. to explore for and produce hydrocarbons in the Republic of Colombia. Under the terms of the agreement, Loon will expend a minimum of US$6 million and will earn a 49% working interest in Kappa's rights in the Abanico Association Contract area. The Abanico block, which covers an area of more than 300 square miles (> 200,000 acres), is located in the Magdalena Valley of central Colombia – an area known for its oil and gas accumulations.

As part of Loon's obligation, it will undertake a 22 km^2 3-D seismic program and will drill a minimum of three wells (two exploratory wells and one development well). Seismic is expected to start during the month of May with the first well expected to spud by the end of June.

Kappa's existing producing property within the contract area is excluded from Loon's earning arrangement.

Doing Business in Colombia

Colombia has a long history of oil and gas exploration and production. Current production is almost 600,000 boepd (mostly oil). More than half of the oil produced is exported to the United States. There are over sixty independent petroleum companies operating in Colombia - a testament to the stability of the country, a favourable business environment and the general prospectivity of the area.

Prolific Oil Producing Area

Colombia shares high quality oil and gas source rocks with neighboring Venezuela where the Maracaibo Basin contains one of the largest petroleum reserves in the world. Colombia has several productive basins, the two most prolific being the Llanos Basin and the Magdalena Basin. The Abanico Block is located in the Upper Magdalena Basin and contains a number of large fields such as Purification, Venganza, Revancha, Capachos, La Hocha and Guando. The Guando Field, developed by Braspetro and Nexen, is located a few miles from the Abanico Block. Guando is the third largest oilfield discovered in Colombia in the past twenty years and the largest since BP discovered the Cusiana-Cupiagua fields in 1989. Proved reserves at Guando are in excess of 100 million barrels of 28° API crude oil.

Work Program

Beginning in May, Loon and Kappa will be undertaking a 3-D survey in the vicinity of Kappa's Abanico Field which will help to further define two of the prospects that Loon is targeting for drilling later this year. In addition, a 2-D seismic survey will be acquired to detail a large lead that could become the fourth location of this year's drilling campaign.

The drilling program is scheduled to begin in the latter part of Q2-2005. The target prospects are briefly described as follows:

Ventilador

This well will target a shallow gas accumulation that has been delineated by three existing Abanico Field wells that produce oil from a deeper reservoir. Loon will drill to 1,700' and, if successful, plans to be selling gas into the local market prior to the end of the fiscal year.

Aleli

The Aleli prospect is a large, well-defined structure located only 9 miles from the >100 million barrel Guando oil field. The Aleli-1 well will be drilled to a depth of 7,800' with the primary target zones being the same zones that are productive at Guando. The Aleli prospect has potential for recoverable reserves of more than

120 million barrels of oil based upon the expect reservoir thickness in the area of the prospect and the amount of closure indicated by existing seismic control. The Guando infrastructure runs within three miles of the Aleli well location providing potential for a relatively speedy tie-in if the initial Aleli well is successful.

Brisas

The Brisas test well will evaluate Tertiary-age sands very close to Kappa's Abanico Field. The 3-D seismic program due to commence in May will help delineate a final location for the Brisas-1 well. Loon is planning to drill the well to roughly 3,500'. The prospect has potential for recoverable reserves in the order of 30-40 million boe.

Revancha Sur

This prospect requires seismic to further delineate its geometry and to define an optimum location for drilling. Loon will acquire 2-D seismic data during the latter part of the second quarter. Loon believes that Revancha Sur has the potential to contain recoverable reserves in excess of 100 million barrels of oil.

Colombia – Other Areas

In addition to Loon's agreement with Kappa covering the Abanico Block, both companies have agreed to work toward expanding the scope of their arrangement in Colombia. Kappa is one of the largest acreage holders in Colombia with some 800,000 acres and also owns and operates its own drilling rigs. Loon and Kappa will work together to evaluate and potentially acquire additional exploration acreage and/or producing assets in Colombia. To this end, Loon has signed Confidentiality Agreements with Kappa covering several new projects in Colombia and both companies will be working toward their acquisition in 2005.

Colombia Locator

Colombia

Colombia is located in South America, between Panama, the Pacific Ocean and the Caribbean Sea to the north, Ecuador and Peru to the south, and Brazil and Venezuela to the East. Colombia has a long and stable history of democratic government and a consistent favourable business environment, particularly for the oil industry, for many years. Colombia has no prohibitive restrictions on investment in this sector or on the repatriation of profits.

Colombia is about twice the size of France or the American state of Texas and approximately the same size as the Canadian province of Ontario, Angola or Egypt.

Key facts:

Area:	**1,138,910 square kilometres**
Coastline:	**3,208 kilometres (Caribbean Sea 1,760 km, North Pacific Ocean 1,448 km)**
Highest Point:	**Pico Cristobal Colon 5,775 m (Andes Mountains)**
Population:	**Approximately 43 million**
Median Age:	**Approximately 26 years**
Language:	**Spanish**
Literacy:	**92.5%**
Religions:	**Roman Catholic 90%, other 10%**
Government:	**Republic; executive branch dominates government structure**
Capital:	**Bogota (~7,100,000)**

Economic Overview – Colombia's economy continues to improve thanks to austere government budgets, focused efforts to reduce public debt levels and an export-oriented growth focus. New exploration is needed to offset declining oil production. Several international financial institutions have praised the economic reforms introduced by the current government which include measures designed to reduce the public-sector deficit below 2.5% of GDP. The government's economic policy and democratic security strategy have engendered a growing sense of confidence in the economy, particularly within the business sector.

SLOVENIA

Petisovci and Dolina Fields

The Petisovci and Dolina fields are located in northeastern Slovenia between the border with Hungary and the border with Croatia. Loon is party to a joint venture agreement covering both of these field areas. The fields occur on the Lovaszi anticline, a large structure with a length of 18 kilometres and a width of about 4 kilometres which straddles the border between Slovenia and Hungary. Approximately 35% of the structure is in Slovenia. The Lovaszi field on the Hungarian side of the structure has produced 50 million barrels of oil and more than 230 Bcf of gas since its discovery in 1942. This is more than ten times the amount of oil and gas produced from the Petisovci and Dolina fields. Given the materially lower relative recovery on the Slovenian side of the anticline from the same reservoirs the Company and its joint venture partners believe significant quantities of oil and gas remain to be produced from the joint venture lands.

Primary Targets

Primary targets underlying the joint venture lands are the Petisovci, Lovaszi, Ratka and Paka zones above a depth of approximately 2,000 metres and the Petisovci-Globocki ("Pg") zone between approximately 2,000 metres and 3,000 metres in depth.

Interest of Loon

Under the terms of the joint venture, Loon pays 40% of the costs to drill and complete wells and receives 38% of revenues before payout and 30% thereafter. In 2004 we participated in the drilling of two wells in Slovenia. The first well, at Pt-123 is subject to the regular joint venture terms summarized above. In the first quarter of 2004 Loon and its joint venture partners finalized an agreement with Grove Energy Limited under which Grove could acquire 65% of the rights of Loon and its joint venture partners in the deeper gas zones. The D-14 well was subject to this arrangement. Loon has a carried working interest of 10.5% in this well.

Pt-123 Well

The Pt-123 well was drilled to a depth of 2,100 metres prior to being tested and completed in the Lovaszi reservoir. The well is currently producing gas at an average rate of approximately 250 Mcfd with all production being sold to a power plant located near the field. A second pressure build-up test will be conducted during the month of May after which the Company will be able to make a more accurate estimate of recoverable reserves. In the event the reserves are in line with our earlier estimate of 2 to 4 Bcf, Loon will plan a program for the rest of 2005 to increase overall natural gas production from the Lovaszi reservoir. This program may include stimulation of the existing producing zone, accessing the reservoir at another location through working over an existing well or the drilling of a new well or wells.

D-14 Well

The D-14 well was spud in October of 2004 and drilled to a depth of 2,805 metres. The main target of the well was the Pg reservoir, a tight gas reservoir that underlies the Petisovic-Dolina oil field. Grove retained Troy Ikoda Limited, a U.K. based third party engineering company to review the Pg reservoir to assess the potential gas-in-place ("GIIP"). This work resulted in Troy Ikoda estimating P90 GIIP of 228 Bcf. Subsequent to receipt of the report, Grove committed to pay for the drilling and fracture stimulation of the D-14 well. In January of 2005 a stimulation program consisting of three fracs in separate sand units within the Pg reservoir was undertaken. Despite running in to well control issues following each frac, the well has not produced commercial quantities of gas. The parties to the Slovenian joint venture are currently assessing what remedial work may be required on the D-14 well in order to obtain commercial gas production.

Shallow Gas Zones in D-14 Well

Numerous oil and gas shows were encountered in shallower reservoirs above 2,000 metres while drilling the well. The shows noted while drilling together with an analysis of wireline logs indicate several sand units which, in the opinion of Loon, merit testing at some point in the future. Loon retained its participating interest of 40% and after payout interest of 30% in these shallower zones.

Future Activity

Loon believes that substantial reserves of natural gas exist in the deeper horizons (Pg and lower) in the area of Petisovci and Dolina and surrounding areas. These fields occur within the Pannonian Basin, a large feature which covers most of Hungary and parts of Romania, Slovakia, Austria, Slovenia and Croatia. Results to date have been disappointing but Loon remains confident that economically recoverable reserves will be produced from the area. The Company is currently working on potential deals in Hungary, Croatia and Slovenia.

Slovenia

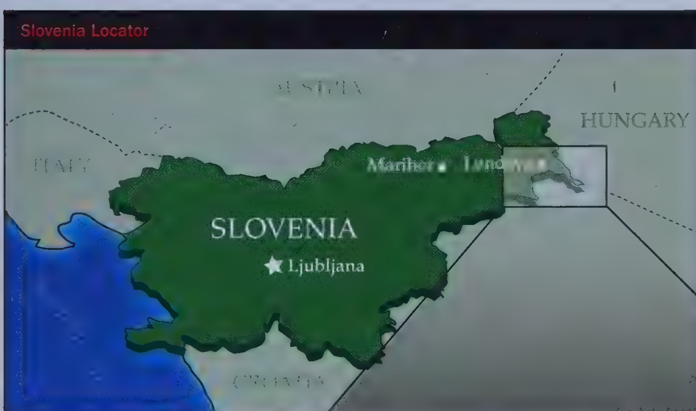
Slovenia is located in south-central Europe, north of Croatia, west of Hungary, south of Austria and east of both Italy and the northern part of the Adriatic Sea. Historical ties to Western Europe, a strong economy and a stable democracy have all contributed to the transformation of Slovenia into a modern capitalist state since it achieved independence in 1991. Slovenia joined NATO in April, 2004 and became a member of the European Union ("EU") on May 1, 2004.

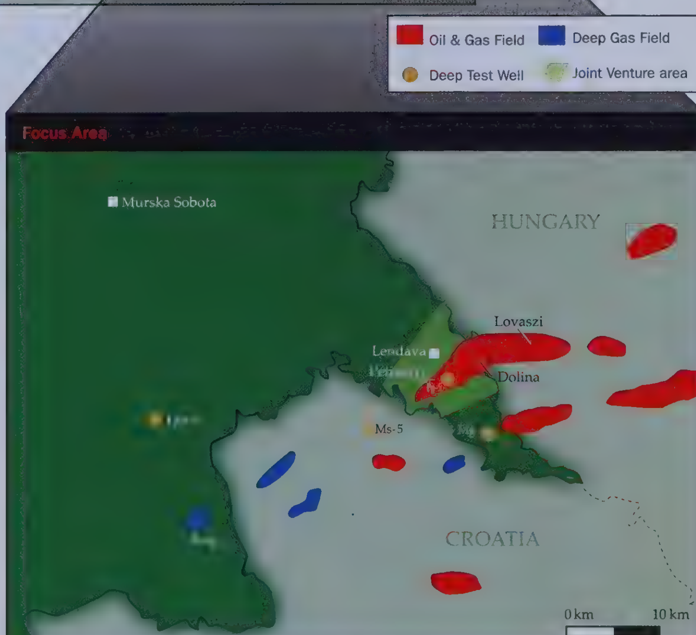
Slovenia is approximately the same size as Belize, Israel or New Jersey, USA.

Key facts:

Area:	20,273 square kilometres
Coastline:	47 kilometres
Highest Point:	**2,864 metres (Slovenian Alps)**
Population:	Approximately 2 million
Median Age:	Approximately 40 years
Language:	Mostly Slovene (German & Croatian widely understood)
Literacy:	100%
Religions:	Roman Catholic 71%, Muslim 1%, Other 28%
Government:	Parliamentary democracy
Capital:	Ljubljana (~270,000)

Economic Overview – with historical ties to Western Europe, Slovenia enjoys a GDP per capita substantially higher than that of the other transitioning economies of Central Europe. Despite the economic slowdown in Europe in the 2001 to 2003 period, Slovenia maintained growth of 3%. Structural reforms, which improved the business environment and allowed for greater foreign participation in Slovenia's economy, have helped to lower unemployment. The emerging economy consumes hydrocarbons at a rate of more than 50,000 barrels of oil per day and more than 1 billion cubic metres per year of natural gas. Essentially 100% of oil and gas consumption is imported. No withholding tax on repatriation of funds and no restrictions on money flow.





Management's Discussion & Analysis

The following analysis and discussion is provided by the management of Loon Energy Inc. ("Loon" or the "Company") should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2004 and 2003.

Basis of Presentation – The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements – The Management's Discussion and Analysis contains the term funds from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Company's performance. The Company's determination of funds from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and funds from operations can be found in the consolidated statements of cash flows in the unaudited interim consolidated financial statements and the audited consolidated financial statements. The Company also presents cash flow from operations per unit whereby per unit amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

BOE Presentation – Barrels of oil equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf : 1 bbl oil is based on an energy equivalency conversation method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All BOE conversions in this report are derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

Summary of Information per BOE

Year Ended December 31	2004	2003
	($)	($)
Gross Revenue	35.68	31.87
Royalties, Net of ARTC	2.48	2.59
Net Revenue	33.20	29.28
Operating Expense	19.19	20.27
Net Operating Revenue	14.01	9.01
General & Administrative	7.24	3.33
Interest Expense	1.08	3.26
Cash Flow per BOE	5.69	2.42

Oil and Gas Revenues

Oil and gas revenue, before royalties, for the year ended December 31, 2004 was $423,031 compared to $523,760 for the year ended December 31, 2003 – a 19% decrease. This was due to a $5.42 per barrel increase in the average oil price offset by, a $0.57 per Mcf decrease in the average price of natural gas and a decrease of 28% in boe production from 16,434 boe in 2003 to 11,856 in 2004.

Year Ended December 31	2004	2003
Oil and Gas Revenues, Before Royalties	$ 423,031	$ 523,760
Oil and NGL Production (bbls)	9,936	13,486
Oil and NGL Price ($/bbl)	$ 35.42	$ 30.00
Gas Production (Mcf)	11,522	17,685
Gas Price ($/Mcf)	$ 6.17	$ 6.74
BOE Production	11,856	16,434
BOE per Day	32	45

2004 and 2003 Annual Production by Field

All of Loon's production during the 2003 and 2004 fiscal years was derived from properties in Canada. The Pt-123 well in Slovenia was undergoing production testing as of the end of the 2004 fiscal year and did not commence regular production until the first quarter of 2005.

	2004			2003		
	Oil	Gas	NGL	Oil	Gas	NGL
Alberta						
Berry	–	11,522	40	–	14,811	–
Carvel	–				2,874	68
Grand Forks	5,608	–	–	6,789	–	–
Saskatchewan						
Silverdale	4,288	–	–	6,629	–	–
Total	9,896	11,522	40	13,418	17,685	68

Royalties

Total royalties, net of ARTC, were $29,375 ($2.48 per BOE) for the year ended December 31, 2004 compared to $42,551 ($2.59 per BOE) for the year ended December 31, 2003. Net royalties represented 7% of gross revenues in 2004 compared to 8% in 2003. Alberta Royalty Tax Credit was $8,092 for the year, due to adjustments recorded based on filed income tax returns.

Year Ended December 31	2004	2003
	($)	($)
Crown Royalties	17,377	10,742
Freehold Royalties	17,979	29,688
Gross Overriding Royalties	2,111	3,423
	37,467	43,853
Alberta Royalty Tax Credit	(8,092)	(1,302)
Net Royalties	29,375	42,551
Net Royalties per BOE (6:1)	2.48	2.59
Royalties as Percentage of Revenue	7%	8%

Operating Expenses

Operating expenses in calendar 2004 were $227,574 ($19.19 per BOE) compared to $333,130 ($20.27 per BOE) in fiscal 2003. All of the Company's oil production is heavy oil, which has high operating costs.

Depletion, Depreciation and Amortization (DD&A)

Depletion and depreciation was $83,058 for the year ended December 31, 2004, which represents a provision of $7.01 per BOE of production. For the year ended December 31, 2003, Loon recorded a DD&A provision of $92,500 ($5.63 per BOE).

General and Administrative

Gross general and administrative costs have increased from $68,450 in 2003 to $206,030 mainly due to management fees paid in 2004 where no such fees were paid in prior periods.

Year Ended December 31	2004	2003
	($)	($)
Gross General and Administrative	206,030	68,450
Overhead Recoveries	(120,200)	(13,800)
Net General and Administrative	85,830	54,650
Per BOE	7.24	3.33

Provision for Income Taxes

There was no cash income tax provision in 2004 and none is expected in 2005.

Capital Expenditures

Capital additions for the year ended December 31, 2004 were $2,095,944 compared to $487,203 for the year ended December 31, 2003.

Year Ended December 31	2004	2003
	($)	($)
Canada	4,193	14,704
Slovenia	2,091,751	472,499
Total	2,095,944	487,203

Shareholders' Equity

The Company issued a total of 22,594,000 common shares in 2004, no shares were issued in 2003. 9,990,000 common shares were issued for cash, 8,000,000 common shares were issued on the conversion of $800,000 in long-term debt, 4,400,000 common shares were issued to purchase additional working interests in the Slovenia properties and 204,000 common shares were issued on exercise of stock options.

Related Party Transactions

At December 31, 2004, the Company held 10,000 shares of TUSK Energy Corporation; a shareholder of the company, purchased at a cost of $10,000, and included in short-term investments. Fair market value of this investment at December 31, 2004 was $29,500.

TKE Energy Trust ("TKE")

TKE supplies certain personnel and general, accounting and administrative service to the Company for a monthly fee of $2,000.

At December 31, 2004, the Company owed TKE and its subsidiaries $30,192 (2003 – $179,736).

At December 31, 2004 the Company held 10,000 shares of TUSK Energy Corporation ("TUSK"), a shareholder of the Company, purchased at a cost of $10,000 and included in short-term investments. Fair market value of this investment at December 31, 2004 was $29,500.

At December 31, 2004 the Company held 10,000 units of TKE, purchased at a cost of $99,968, and included in short-term investments. Fair market value of this investment at December 31, 2004 was $95,000. These units were sold in February, 2005 for net proceeds of $107,930.

One officer and a director of the Company is also an officer and director of TUSK and TKE and one director of the Company is an officer of TUSK and TKE.

Liquidity and Capital Resources

Loon had working capital of $476,396 at December 31, 2004.

On March 31, 2005 Loon closed a private placement of 21,052,636 common shares at $0.95 per share to raise gross proceeds of $20,000,004. Net proceeds from the financing will be used for the Company's capital programs and for general corporate purposes.

On an ongoing basis Loon will typically utilize three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt where deemed appropriate and new equity issues if available on favorable terms. When financing corporate acquisitions, Loon may also assume certain future liabilities. Commodity prices and production volumes have the largest impact on Loon's ability to generate adequate cash flow to meet all its obligations. A prolonged decrease in commodity prices would negatively affect Loon's cash flow from operations and would also likely result in a reduction in the amount of bank loan available. If Loon's capital expenditure program does not result in sufficient additional reserves and/or production if would likely have a negative impact on Loon's liquidity.

Loon may adjust its capital expenditure program depending on the commodity price outlook. Loon believes that internally generated cash flow and incremental bank debt should be sufficient to finance current operations and planned capital spending in the next year.

Business Risks

The marketability and price of products owned or that may be acquired or discovered by Loon will be affected by numerous factors beyond the Company's control. Loon must compete in all aspects of its operations with a number of other corporations that have equal or greater technical or financial resources.

The ability of the Company to market its natural gas may depend on its ability to acquire space in pipelines that deliver natural gas to commercial markets. The Company is also subject to market fluctuations in the prices of products, exchange rates, uncertainties related to the proximity of its reserves to pipelines and processing facilities and extensive government regulation.

Quarterly Data

The following tables set forth selected quarterly financial information for the last eight financial quarters.

	Fourth Quarter 2004	Third Quarter 2004	Second Quarter 2004	First Quarter 2004
Production per Day				
Oil and NGLs (bbls)	30	26	22	40
Natural Gas (Mcf)	38	40	18	30
BOE	37	33	25	45
Netback per BOE ($)	52.20	(13.21)	(35.42)	6.72
Petroleum and Natural Gas Sales, Net ($)	101,843	114,854	82,900	94,060
Funds From Operations ($)	177,675	(39,504)	(80,842)	27,232
Net Income (loss)	29,302	(316,444)	(139,462)	(14,468)
Per Common Share (basic) ($)	0.00	(0.01)	0.00	0.00
Per Common Share (fully diluted) ($)	0.00	(0.01)	0.00	0.00

	2003	2003	2003	2003
Production per Day				
Oil and NGLs (bbls)	42	37	31	47
Natural Gas (Mcf)	50	32	44	68
BOE	50	43	38	49
Netback per BOE ($)	(4.02)	(0.16)	26.97	16.20
Petroleum and Natural Gas Sales, Net ($)	113,465	104,857	97,947	164,940
Funds From Operations ($)	(18,480)	(621)	76,078	71,423
Net income (loss)	(111,030)	(12,471)	35,678	27,023
Per Common Share (basic) ($)	0.00	0.00	0.00	0.00
Per Common Share (fully diluted) ($)	0.00	0.00	0.00	0.00

Fourth Quarter Analysis

	Fourth Quarter 2004	Third Quarter 2004	Fourth Quarter 2003
Daily Production			
Oil and NGLs, bpd	30	26	42
Natural Gas, Mcfd	38	40	50
BOEPD	37	33	50
Summary of Product Prices			
Oil and NGLs per bbl	$ 33.61	$ 40.37	$ 25.41
Gas per MCF	$ 5.11	$ 6.71	$ 5.22
Financial			
Oil and Gas Revenues, Net	101,843	114,854	113,465
Other Income	16,076	1,088	15,255
Operating Costs	12,280	105,106	123,249
Interest on Long-Term Debt	–	–	11,617
General and Administrative	(72,036)	50,340	12,766
Depletion, Depreciation and Accretion	34,373	17,940	31,050
Financing Cost	114,000	–	–
Stock-Based Compensation	–	259,000	–
Funds from Operations	177,675	(39,504)	(18,480)
Net Income (Loss)	29,302	(316,444)	(111,030)
Per Unit Basic	0.00	0.00	0.00
Per Unit Diluted	0.00	0.00	0.00

General and Administrative

G&A in Q4 2004 was a credit of $72,036 due to the recovery of overhead from partners in the Slovenia programs.

Financing Costs

Financing costs were $114,000 in Q4 2004 compared to nil in Q3 2004. The expense recorded in Q4 2004 was the cost of issuing share purchase warrants associated with the extension of the term of the long term debt, which was subsequently converted. Expense in Q3 2004 was for stock options granted in the quarter.

Refer to the 2004 compared to 2003 MD&A for explanations for other variances.

Application of Critical Accounting Estimates

The significant accounting policies used by Loon are disclosed in note 2 to the Consolidated Financial Statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and is included in Management's Discussion and Analysis to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results being reported. Loon's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. The Company might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

Oil and Gas Reserves

Under NI 51-101, "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. There was no such consideration of probability under the Canadian Securities Administrators' National Policy 2-B ("NP-2B"). In the case of "Probable" reserves, which are obviously less certain to be recovered than Proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves. With respect to the consideration of certainty, in order to report reserves as Proved plus Probable, the reporting company must believe that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of Reserve evaluation.

The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's plans. The effect of changes in proved oil and gas reserves on the financial results and position of the Company is described under the heading "Full Cost Accounting for Oil and Gas Activities".

Proved plus Probable (or "2P") reserves as defined in NI 51-101 are viewed by many industry participants as being comparable to the "Established" reserves definition that was used historically. The 2P reserves form the basis for calculation of reserve life indices and are considered as the more accurate estimate of the actual reserves quantities.

Full Cost Accounting for Oil and Gas Activities

Depletion Expense

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit-of-production method based on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Withheld Costs

Certain costs related to unproved properties including Slovenia, are excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rate, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Impairment of Long-Lived Assets

The Company is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

Asset Retirement Obligations

Effective January 1, 2004, the Company changed its accounting policy with respect to accounting for asset retirement obligations. The Company, under the current policy, is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

New Accounting Standards

Stock-Based Compensation Plans

In September 2003, the CICA issued an amendment to Section 3870 "Stock-based Compensation and Other Stock-based Payments". This standard provides for the retroactive adoption of fair value accounting effective January 1, 2004. After January 1, 2004 the fair value of stock-based compensation and other transactions has been recognized as an expense in the financial statements.

Oil and Gas Full Cost Accounting

In July 2003, the Accounting Standards Board issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" which replaced Guideline 5.

The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and measure the impairment amount as the difference between the carrying amount and the fair value.

Continuous Disclosure Obligations

Effective March 31, 2004, the Company and all reporting issuers in Canada are subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective for fiscal years beginning on or after January 1, 2004. The instrument imposes shorter reporting periods for filing and enhanced disclosure requirement for annual and interim financial statements and MD&A. Under this new instrument, it will no longer be mandatory for the Company to mail annual and interim financial statements and MD&A to shareholders, but rather these documents will be provided on an "as requested" basis. It is Loon's intention to make these documents available on the Company's web site on a continuous basis.

Additional Information

Additional information regarding the Company and its business and operations is available on the Company's company profiles at www.sedar.com. Copies of the information can also be obtained by contacting the Company at Loon Energy Inc. 1950, 700 – 4th Avenue S.W., Calgary, Alberta T2P 3J4 (Phone: 403-264-8877) or by e-mail at mwiltshire@loon-energy.com. This information is also accessible on the Company's web site at www.loon-energy.com.

Forward Looking Statements

Certain information regarding Loon set forth in the document, including management's assessment of Loon's future plans and operations, contain forward looking statements that involve substantial known and unknown risks and uncertainties. These forward looking statements are subject to numerous risks and uncertainties, certain of which are beyond Loon's control, including the impact of general imprecision of reserve estimates, environmental risks, taxation policies, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal or external sources. Loon's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward looking statements and, accordingly, no assurance can be given that any of events anticipated by the forward looking statements will transpire or occur, or if any of them do so, what benefits that Loon will derive therefrom.

Management's Report

The management of Loon Energy Inc. is responsible for the financial information and operating data presented in this annual report.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respect. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

Loon Energy Inc. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors, composed of non-management directors, meets regularly with management, as well as the external auditors, to discuss auditing (external and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. KPMG LLP have full and free access to the Audit Committee.

"signed"

Norman W. Holton
President
and Chief Executive Officer

"signed"

Gordon K. Case
chief financial officer

April 27, 2005

Auditors' Report

To the Shareholders of Loon Energy Inc.

We have audited the consolidated balance sheets of Loon Energy Inc. as at December 31, 2004 and 2003 and the consolidated statements of operations and deficit and cash flow for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and the disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and the changes in its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

"Signed"
KPMG LLP
Chartered Accountants

Calgary, Canada
April 27, 2005

CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31, 2004 AND 2003

	2004	2003
	$	$
		(Restated – Note 4)
ASSETS		
Current		
Cash	127,016	48,255
Accounts Receivable	622,606	282,514
Short-Term Investments (Note 10)	124,800	–
Prepaid Expenses and Deposits	22,728	26,670
	897,150	357,439
Property, Plant and Equipment (Note 5)	4,625,952	2,613,066
	5,523,102	2,970,505
LIABILITIES		
Current		
Accounts Payable	420,754	338,135
Asset Retirement Obligation (Note 4)	64,775	59,200
Long-Term Debt (Note 6)	–	800,000
SHAREHOLDERS' EQUITY		
Capital Stock (Note 7)	5,462,392	2,059,917
Contributed Surplus (Note 3 and 7)	319,000	–
Deficit	(743,819)	(286,747)
Future Operations (Note 1)	5,037,573	1,773,170
	5,523,102	2,970,505

See Accompanying Notes

APPROVED BY THE BOARD:

"signed"

Norman W. Holton
Director

"signed"

Kenneth R. Heuchert
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND DEFICIT

FOR YEARS ENDED DECEMBER 31, 2004 AND 2003

	2004	2003
	$	$
		(Restated – Note 4)
Oil and Gas Revenues, Net of Royalties	393,657	481,209
Other Income	17,164	88,473
	410,821	569,682
Expenses		
Operating	227,574	333,130
General and Administrative	85,830	54,650
Interest on Long Term Debt	12,856	53,502
Stock-Based Compensation (Note 6 and 7)	323,000	–
Financing Cost (Note 6)	114,000	–
Depletion, Depreciation and Accretion	88,633	97,700
	851,893	538,982
Net (Loss) Income Before Future Taxes	(441,072)	30,700
Future Income Taxes	-	91,500
Net Loss	(441,072)	(60,800)
Deficit; Beginning of Year as Previously Reported	(296,147)	(237,547)
Stock-Based Compensation – Retroactive Adoption (Note 3)	(16,000)	–
Asset Retirement Obligations – Retroactive Adoption (Note 4)	9,400	11,600
Deficit; Beginning of Year as Restated	(302,747)	(225,947)
Deficit; End of Year	(743,819)	(286,747)
Loss Per Share, Basic and Diluted	(0.01)	0.00

See Accompanying Notes

CONSOLIDATED STATEMENTS OF CHANGES IN CASH FLOW

FOR THE YEARS ENDED DECEMBER 31, 2004 AND 2003

	2004	2003
	$	$
		(Restated – Note 4)
Net Inflow (outflow) of Cash Related to the following Activities:		
Operating		
Net Loss	(441,072)	(60,800)
Item not Affecting Cash		
Depletion, Depreciation and Accretion	88,633	97,700
Stock-Based Compensation	323,000	–
Financing Costs	114,000	–
Future Income Taxes	–	91,500
	84,561	128,400
Changes in Non-cash Operating Working Capital Items (Note 9)	(378,331)	75,262
	(293,770)	203,662
Financing		
Issue of Share Capital	1,819,500	–
Share Issue Expense	(11,025)	–
	1,808,475	–
Investing		
Property, Plant and Equipment	(1,435,944)	(487,203)
Proceeds on Sale of Property, Plant and Equipment	–	320,000
	(1,435,944)	(167,203)
Net Cash Inflow	78,761	36,459
Cash Position; Beginning of Year	48,255	11,796
Cash Position; End of Year	127,016	48,255
Interest Paid	66,358	–

See Accompanying Notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2004 AND DECEMBER 31, 2003

1 Future Operations

The recovery of oil and gas property costs capitalized and investment costs and the repayment of creditors is dependent on Loon Energy Inc.'s ("Loon or the Company") the Company's ability to generate profitable operations and on the continued cooperation of major creditors. Note 12 outlines equity raised of $20 million subsequent to December 31, 2004.

2 Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, where necessary, the consolidated financial statements include amounts based on informed estimates and best judgments of management.

a) Principles of consolidation

The financial statements consolidate the accounts of the Company and its wholly owned subsidiary, Zama Energy Ltd.

b) Petroleum and Natural Gas Properties

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized within costs centres on a country by country basis. All such costs are accumulated in two cost centres representing the Company's activities undertaken in Canada and Slovenia. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

Petroleum and natural gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying value of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs are discounted using the risk-free rate. Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

Costs of acquiring and evaluating significant unproved petroleum and natural gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved reserves are attributable to such interest or until impairment occurs.

c) Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

d) Asset Retirement Obligations

The Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the proved reserves. The liability is adjusted each reporting period to reflect the passage of time,

with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

e) Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

f) Transportation Expenses

Transportation expenses are presented as an expense in the Statement of Loss and Deficit, within operating expenses.

g) Joint Ventures

Substantially all of the Company's oil and gas activities are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities. One of the Company's joint venture partners is TUSK Energy Corporation ("TUSK"), a shareholder of the Company. Another joint venture partner is TKE Energy Trust ("TKE"). One director and officer of the Company is a director and officer of TKE and one director of the Company is an officer of TKE. All dealings are under normal industry conditions.

h) Measurement Uncertainty

The amounts recorded for depletion and depreciation of capital assets and the provision for asset retirement obligations are based on estimates. The ceiling test is based on such factors as estimated proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements of future periods is uncertain.

i) Income Taxes

The Company uses the liability method of accounting for income taxes. Under the liability method, future tax assets and liabilities are recognized for the future consequences attributable to differences between the financial statements carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

j) Per Share Amounts

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period. Diluted per share amounts are calculated based on the treasury stock method which assumes that any proceeds, obtained on exercise of option would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

k) Stock Based Compensation Plan

The Company applied the fair value method for valuing stock option grants. Under the method, compensation costs, attributable to share options granted to employees, contractors, officers and directors of Loon is measured at fair value at the grant date and expenses with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Company has not incorporated an estimated forfeiture rate for stock options, rather, the company accounts for a actual forfeiture as they occur.

l) Financial Instruments

The carrying values of accounts receivable and accounts payable and accrued liabilities approximate their fair value due to the relatively short periods to maturity of the instruments. Long-term debt bears interest at floating rates and therefore the carrying value approximates its fair value.

m) Comparative Figures

Certain comparative figures have been reclassified to conform with the current financial statement basis of presentation.

3 Change in Accounting Policies

a) Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new Canadian accounting standard for asset retirement obligations. The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in fair value of the liability through charges to accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depreciation, depletion and amortization of the underlying asset. Note 4 discloses the impact of the adoption of the new standard on the financial statements.

b) Stock-based Compensation

Effective January 1, 2004 the Company adopted the new Canadian accounting standard for stock based compensation, retroactively without restatement of prior periods. The recommendations require the Company to record a compensation expense with a corresponding increase to contributed surplus over the vesting period based on the fair value of options granted to employees and directors. Upon the exercise of the option, consideration received together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. This change resulted in a decrease to retained earnings of $16,000 and an increase to contributed surplus of $16,000.

c) Property, Plant and Equipment – Oil and Gas

Effective January 1, 2004 the Company adopted new Canadian guidelines which modify the way the ceiling test is performed. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected future cash flows which are discounted using a risk free rate. The adoption of the new guidelines had no effect on the Company's financial results.

4 Asset Retirement Obligations

The Company retroactively adopted the new recommendations on the recognition of the obligations to retire long-lived tangible assets. The change was effective January 1, 2004 and the revision was applied retroactively.

The effect of the adoption is presented below as increases (decreases):

Balance Sheet

As of	December 31, 2003	December 31, 2002
Asset retirement costs, included in property, plant and equipment	41,000	41,000
Accumulated amortization on asset retirement costs included in property, plant and equipment	16,600	12,100
Asset retirement obligations	59,200	54,000
Site restoration liability	(44,200)	(36,700)
Retained earnings	9,400	11,600

Income Statement

Year Ended	December 31, 2003	December 31, 2002
Accretion expense	5,200	5,200
Depletion and depreciation on asset retirement costs	4,500	4,500
Provision for future site restoration	(7,500)	(14,800)
Net income impact	(2,200)	5,100
Basic and diluted net income per share	–	–

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $117,000

which will be incurred between 2004 and 2029. The majority of the costs will be incurred between 2008 and 2020. A credit-adjusted risk-free rate of 9.125 percent and an inflation rate of 1.5 percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligations is provided below:

Asset retirement obligations

Year Ended	December 31, 2004	December 31, 2003
Balance, beginning of period	59,200	54,000
Liabilities incurred in period	–	–
Liabilities settled in period	–	–
Accretion expense	5,575	5,200
Balance, end of period	64,775	59,200

5 Property, Plant And Equipment

	Cost	December 31, 2004 Accumulated Depletion & Depreciation	Net Book Value
Oil and Gas Properties – Canada	$ 2,661,614	$ 2,181,158	$ 480,456
Oil and Gas Properties – Slovenia	4,144,750	–	4,144,750
Office Equipment	9,746	9,000	746
	$ 6,816,110	$ 2,190,158	$ 4,625,952

	Cost	December 31, 2003 Accumulated Depletion & Depreciation	Net Book Value
Oil and Gas Properties – Canada	$ 2,657,421	$ 2,098,100	$ 559,321
Oil and Gas Properties – Slovenia	2,052,999	–	2,052,999
Office Equipment	9,746	9,000	746
	$ 4,679,166	$ 2,107,100	$ 2,613,066

Depending on the status of the Slovenian cost centre, the recovery of the costs outlined above is dependent on the Company, achieving commercial production or sale and/or obtaining additional financing.

Adoption of the new guideline for oil and gas accounting using the full cost method, as outlined in note 3, had no effect on the Company's financial statements, based on the ceiling test prepared on initial adoption on January 1, 2004 using commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's Canadian reserves. The Company performed a ceiling test calculation at December 31, 2004 resulting in the undiscounted cash flows from Canadian proved reserves and the lower of cost and market of unproved Canadian properties exceeding the carrying value of oil and gas assets. The following table summarizes the future benchmark prices the Company used in the ceiling test for the Canadian Cost Centre:

	Crude Oil West Texas (US$/bbl)	Natural Gas Edmonton (Cdn$/bbl)	AECO (Cdn$/mmbtu)
2005	42.00	50.22	6.55
2006	40.00	49.00	6.30
2007	38.00	47.72	5.80
2008	36.00	45.15	5.55
2009	35.00	43.87	5.63
Thereafter (2)	1.5%	1.5%	1.5%

(1) Future prices incorporated a $0.82 US/Cdn exchange rate for 2005, $0.80 US/Cdn for 2006 and $0.78 US/Cdn thereafter.

(2) Percentage change of 1.5% represents the change in future prices each year after 2009 to the end of the reserve life.

No administrative overhead expenditures directly related to the acquisition, exploration and development of petroleum and natural gas reserves have been capitalized in either of the years ended December 31, 2004 or 2003. No interest has been capitalized to oil and gas properties in either of the years ended December 31, 2004 or 2003.

6 Long-term Debt

	December 31, 2004	December 31, 2003
Debentures	$ –	$ 800,000
Balance	–	800,000
Less: Current portion	–	–
	$ –	$ 800,000

On February 27, 2004 the debenture holders agreed to extent the term of the debenture to January 1, 2006. In consideration for the extension, the Company granted the debenture holders an aggregate of 1,600,000 share purchase warrants which entitled the holders thereof to acquire 1,600,000 common shares of Loon at $0.10 per common share at any time prior to January 1, 2006. The cost of issuing the warrants was calculated using a Black-Scholes model and was determined to be $114,000.

On March 31, 2004, the debenture holders elected to convert their debentures into 8,000,000 common shares of the Company (See Note 7).

7 Share Capital

a) Authorized share capital:

Unlimited number of common shares

Unlimited number of preferred shares

b) Issued:

Common shares were issued as follows :

	December 31, 2004		December 31, 2003	
	Number	Amount ($)	Number	Amount ($)
Common Shares:				
Balance Beginning of Year	23,135,708	2,059,917	23,135,708	2,059,917
Issued for Cash	9,990,000	1,798,200	–	–
Issued on Exercise of Stock Options	204,000	41,300	–	–
Issued on Conversion of Long-Term Debt	8,000,000	800,000	–	–
Issued for Purchase of Additional Interest Of Slovenia Property	4,400,000	660,000	–	–
Share Issue Costs (Net of Tax Effect)	–	(11,025)	–	–
Balance End of Year	45,729,708	5,348,392	23,135,708	2,059,917
Share Purchase Warrants:				
Balance Beginning of Year	–	–	–	–
Issued During the Year	1,600,000	114,000	–	–
Balance End of Year	1,600,000	114,000	–	–
Total		5,462,392		2,059,917

c) Per Share Amounts

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2004 was 38,678,064 (2003 – 23,135,708).

d) Stock Options

Effective January 1, 2002, the Company prospectively adopted the new Canadian Accounting Standard with respect to the accounting stock based compensation. In accordance with the new standards, the Company elected to continue its policy that no compensation is recorded on the grant of employee stock options and consideration paid on the exercise of such options is recorded as share capital. In addition, the new standard required a pro forma disclosure of the fair value based method of accounting for other stock based payments. The estimated fair value of stock options issued was determined using the Black-Scholes option pricing model assuming a risk free interest rate of 5%, volatility of 56% and are exercisable immediately. Had compensation cost for the Company's stock based compensation been determined based on the fair value at the grant dates after January 1, 2002 the Company's net loss would have been $73,600 and the loss per share would have been the same as previously reported.

Stock options, entitling the holder to purchase shares from the Company, have been granted to directors, officers and certain employees of the Company. The stock options vest and are exercisable immediately following the grant of the options.

A summary of the status of the Company's stock option plan as of December 31, 2004 and 2003, and changes during the years ending on those dates presented below.

	2004		2003	
	Options	Weighted Average Exercise Price ($)	Options	Weighted Average Exercise Price ($)
Outstanding at Beginning of Year	2,213,000	0.12	1,963,000	0.12
Granted	2,200,000	0.20	250,000	0.11
Exercised	(204,000)	0.10	–	0.00
Outstanding and Exercisable at End of Year	4,209,000	0.16	2,213,000	0.12

At December 31, 2004, the options granted are estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair marker value of options granted during the first quarter and the assumptions used in their determination are as noted below:

Stock-based Compensation:

The fair values of all common share options granted are estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of options granted during the year ended December 31, 2004 and the assumptions used in their determination are as noted below:

Year Ended	December 31, 2004
Weighted average fair market value per option	3.143
Risk-free interest rate (percent)	3.16
Volatility (percent)	149
Expected life (years)	5

As described in note 3, the Company adopted the fair value based method of accounting for stock-based compensation for its stock option plan retroactively without restatement of prior periods. Retained earnings at January 1, 2004 was decreased by $16,000 with an increase to contributed surplus of $16,000. Beginning January 1, 2004, stock compensation is being recognized in earnings.

Contributed Surplus

The following table reconciles the Company's contributed surplus:

	Year Ended December 31, 2004	Year Ended December 31, 2003
Balance, Beginning of Year	–	–
Retroactive Adoption of Unit Based Compensation	16,000	–
Stock Based Compensation Expense	323,000	–
Common Shares Rights Exercised	(20,000)	–
Balance, End of Year	319,000	–

8 Income Taxes

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory rate of 41.2% of income before income taxes. The reasons for the differences are as follows:

	Year Ended December 31 2004	Year Ended December 31 2003
	($)	($)
Expected Tax (Recovery) Expense	(171,600)	(13,550)
Non-deductible Crown Charges	6,100	4,000
Alberta Royalty Tax Credit	(2,800)	(500)
Resource Allowance	(7,000)	(7,800)
Stock-Based Compensation	170,000	–
Valuation Allowance	5,300	109,350
Actual Tax (Recovery) Expense	–	91,500

The components of the future tax asset at December 31, 2004 and 2003 is as follows:

	Year Ended December 31 2004	Year Ended December 31 2003
	($)	($)
Property, Plant and Equipment	243,600	223,300
Share Issue Costs	57,200	53,300
Asset Retirement Liability	22,400	15,300
Capital Losses Carried Forward	215,700	215,700
Losses Carried Forward	14,200	40,200
	553,100	547,800
Less Valuation Allowance	(553,100)	(547,800)
	–	–

9 Changes in Non-Cash Working Capital

	December 31 2004 ($)	December 31 2003 ($)
Short-Term Investments	(124,800)	61,232
Accounts Receivable	(340,092)	(184,851)
Prepaid Expenses	3,942	–
Accounts Payable	82,619	198,881
	(378,331)	75,262

10 Related Party Transactions

TKE supplies certain personnel and general, accounting and administrative service to the Company for a monthly fee of $2,000.

At December 31, 2004, the Company owed TKE and its subsidiaries $30,192 (2003 - $179,736).

At December 31, 2004 the Company held 10,000 shares of TUSK, purchased at a cost of $10,000, and included in short-term investments. Fair market value of this investment at December 31, 2004 was $29,500.

At December 31, 2004 the Company held 10,000 units of TKE, purchased at a cost of $99,968, and included in short-term investments. Fair market value of this investment at December 31, 2004 was $95,600. These units were sold in February, 2005 for net proceeds of $107,930.

One officer and a director of the Company is also an officer and director of TUSK and one director of the Company is an officer of TUSK.

Loon has agreed to pay certain royalties to former shareholders of a joint venture partner on production revenues received by Loon in Slovenia. 1.0% of this royalty will be paid to be a director of Loon.

11 Financial Instruments

a) Credit Risk

The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. To mitigate this risk, the Company sells substantially all of its production to two primary purchasers under normal industry sale and payment terms. The Company may be exposed to certain losses in the event on non-performance by counterparties to commodity price contracts.

b) Foreign Currency Exchange Risk

The Company is exposed to foreign currency fluctuations as crude oil prices received are referenced in U.S. dollar denominated prices.

c) Fair Value of Financial Instruments

The Company's financial instruments recognized in the balance sheet consist of accounts receivable, short-term investments and accounts payable. The fair value of these financial instruments approximate their carrying amounts due to their short terms to maturity.

12 Subsequent Events

a) On March 31, 2005 the Company closed a private placement, of common shares at $0.95 for total gross proceeds of $20 million.

The offering consisted of the 15,789,478 common shares plus an over-allotment of 5,263,158 common shares. The underwriters received a commission of 6% of the gross proceeds and were granted 500,000 broker warrants. Each broker warrant entitles its holder to acquire one common share of the Corporation at a price of $0.95 until March 31, 2006. The common shares issued at closing and any additional common shares issued on exercise of broker warrants are subject to a four month hold period.

b) On April 13, 2005, the Company announced a joint venture agreement with a Columbian company whereby Loon has agreed to expend a minimum of US$6 million to earn a 49% working interest in certain of the Columbian company's properties in Columbia.

Corporate Information

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Ed Beaman
Engineering Advisor

Deb Cooke
Senior Accountant

Jock Graham
Exploration Advisor

Norm Holton
Chairman & CEO

Brian Mainwaring
Corporate Secretary

Michele Wiltshire
Executive Assistant

Listing

TSX Venture Exchange
Symbol: LEY

Subsidiaries

Zama Energy Ltd.

Auditor

KPMG LLP
Calgary, Alberta

Banker

National Bank of Canada
Calgary, Alberta

Legal

Gowling Lafleur Henderson LLP
Calgary, Alberta

Registrar & Transfer Agent Services

Computershare Investor
Calgary, Alberta

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